

Status Report

THE EFFECTS OF VISCOUS FORCES
ON THREE-PHASE RELATIVE PERMEABILITY

Project BE9, Milestone 3, FY88

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ABSTRACT

The overall objective of project BE9 is to develop guidelines for improving the accuracy of three-phase relative permeability determinations. This need is dictated by considerable data scatter and nonagreement on the results observed by almost all researchers. To improve the methodology, a better understanding of the role of viscous, gravity, and capillary forces on three-phase flow is required. This report summarizes the progress made on studying the effects of viscous forces on three-phase relative permeability, which represents tasks 1 and 2 scheduled for completion by November 1987 and April 1988, respectively.

This report includes a brief discussion of previous studies on the compilation and implementation of important operating criteria and on improvements in in situ measurements of saturations. It also includes a re-evaluation of the previous results in the light of new information, and finally, it presents some of the newly acquired data.

INTRODUCTION

The following remarks by Baker (SPE/DOE 17369, April 1988) represent the state-of-the-art for relative permeability measurements:

"A review of three-phase relative permeability data and models available in the literature indicates there are many problems remaining to be solved. From an experimental standpoint the most important problem is obtaining good quality relative permeability and saturation history data. . ."

Literature Review

The published three-phase relative permeability data were reexamined with the objective of comparing the results of various studies. This study

revealed that there is no consensus on the shape of the isoperms on ternary diagrams. The only agreement was in the observation that the saturation envelope on a ternary diagram in which all three phases are mobile is rather small. There was, however, little basis for comparison because the studies were performed under a wide variety of operating conditions.¹ These results were, therefore, analyzed on the basis of experimental conditions for comparison between similar studies. The results are summarized in appendix A.²⁻¹² Once again, no agreement was found either in the shape of saturation isotherm data plots or relative permeability values even for similar cores such as Berea.

This lack of repeatability is not surprising because three-phase relative permeability tests are experimentally tedious. First, a reasonably accurate determination of saturation when more than two phases are involved is difficult, especially for steady-state tests. Material-balance techniques are generally shown to be inaccurate when the pore volumes of injectant are large, and in situ saturation measurement techniques must be used. Other relative permeability measurement techniques sometimes used are unsteady-state and centrifuge methods, but their results are only approximate because of the complexity of the mathematical solutions.

Another potential problem is the lack of scaling criteria. Whereas such criteria have been established for two-phase, liquid-liquid flow, scarcely any work on scaling criteria for three-phase flow has been reported. In the absence of scaling criteria, solving experimental problems such as capillary end effects becomes difficult. In addition, the ratio between capillary, viscous, and gravity forces influences the irreducible saturation levels. The end-point saturations could have a pronounced effect on the shape of the isoperms.

An important complication arises from saturation hysteresis effects. It is difficult to change core saturation conditions in a controlled sequence during three-phase flow experiments. As relative permeabilities are saturation history dependent, the manner in which an experiment is conducted has an effect on the appropriateness of the results.

Some investigators cleaned and resaturated cores during relative permeability experiments to facilitate achieving desired saturation conditions. Changes in core wettability due to cleaning also affect relative permeability results.

Yet another difficulty is found in representing three-phase data. Typically, the scatter in relative permeability data on a ternary diagram is so great that the isoperms cannot be drawn accurately by manual interpolation. The data are therefore analyzed by use of one of many available computer subroutines. The shape of the resulting isoperms drawn from computer interpolations is influenced by operator bias. To avoid the need for interpolation, some researchers have held one of the phases stationary using semipermeable membranes. In some recent studies, the experiments have been performed on computer-automated equipment to adjust the rates automatically so that the saturation of each phase stays on the locus of a preassigned isoperm on one of the three ternary diagrams. This scheme can reduce data scatter significantly, and the analysis of data becomes much easier. However, it might also increase the role of hysteresis and result in higher inaccuracies.

OPERATING CRITERIA

A preliminary standard operating procedure (SOP) was established for reducing the characteristic data scatter in three-phase relative permeability experiments. This procedure emphasizes the compilation of data which should not require interpolation. The hysteresis effects should also be reduced to a minimum. This SOP is described in a 15-page document that contains 5 appendices and involves 53 steps to obtain quality data. It also describes core handling, cleaning and initial saturation, criteria for maximum and minimum rates and pressure drops, saturation determination by material balance/in situ techniques, and a constant-permeability, variable-rate technique to obtain predetermined isoperms.

IMPROVEMENTS IN IN SITU MEASUREMENTS AND PROCEDURES

X-Ray Scans

Routine tests conducted during the first quarter of this project year to check the x-ray unit showed that the x-ray beam was projecting to a point 1.6 cm below the center of the x-ray detector. The x-ray tube and shutter assembly were incrementally raised as x-ray scans were taken through ordinary, unopened Polaroid film frames. The x-rays exposed a portion of the film in the area of penetration. After multiple trials, the final picture indicated that the source and detector were suitably aligned.

A series of x-ray scans of core samples were taken under various saturation conditions to demonstrate the effect of varying the pulse height analyzer settings on the x-ray calibration for oil saturation. The pulse height analyzer filters the electrical pulses from the x-ray detector before they are sent to the counter for intensity interpretation. Adjustment of the pulse height analyzer settings allows the operator to selectively look at intensities from a narrow wavelength band in the x-ray spectrum.

After the optimum x-ray power settings had been established, pulse height distribution curves were constructed for the samples, and x-ray scans at various window settings were obtained. Figure 1 shows the pulse height distribution curve for Berea sandstone core No. 13 as it was scanned under dry, 100% brine-saturated, and 70% oil-saturated (residual water) conditions. Peaks for each of the saturation conditions occurred at about 48% on the x-scale of figure 1. Figure 2 shows scan results for core No. 13 (one position) as oil saturation versus natural log of emergent x-ray intensity. As shown by the figure, the narrowest window setting (46/53) provided the best degree of linearity in the oil saturation versus x-ray intensity calibration. Similar results were obtained for other samples. The results from these tests were used to select the optimum window settings for calibrating x-ray response to tagged oil saturation.

Microwave Scans

Analyses of microwave scan data revealed that some microwave energy was bypassing or radiating above and below the cores during typical microwave scans even though lens-focused sending and receiving antennas were used. The

energy that reached the microwave receiving antenna (and detector) without penetrating a core caused the effectiveness of the microwave calibration for brine saturation determination at high water saturation conditions to diminish. To reduce this effect, a microwave absorbing material was used to construct shields which prevent nonemergent microwaves from reaching the receiving antenna. The minimum detectable microwave power baseline was reduced from 50 to 2 μW , substantially improving the resolution of the system for brine saturation measurements.

The Berea sandstone samples currently in use for relative permeability tests have rectangular cross sections of 2 cm thickness (width) and 5 cm height. To alleviate gravity effects that might lead to segregation of the test fluids, an arrangement was made to switch the orientation of a core temporarily from horizontal to vertical for x-ray and microwave scans. This was done by using hinged stands which allow the 2 cm widths to be oriented parallel to the horizontal plane during flow tests.

The rectangular shape of rock samples used in this investigation was selected as the most appropriate shape for microwave penetration. The 2-cm thickness limitation was imposed based on microwave detection constraints. As metallic coreholders are unsuitable for microwave brine saturation measurement techniques, the cores are jacketed with epoxy resin and tested without confining pressure. While microwave techniques have been found to be very effective for measuring brine saturations during relative permeability experiments, the limitations on experimental techniques imposed by using the microwave apparatus are fairly restrictive. However, tests conducted on a nonmetallic coreholder that was recently received demonstrated that the coreholder may be used to apply confining pressure to epoxied cores and still allow for adequate microwave penetration. Additionally, a detector capable of measuring microwave power in the 100 to 10 μW range should become available during the summer of 1988. The nonmetallic coreholder will add a new degree of flexibility to relative permeability experiment design, and the low-range power detector promises to substantially improve the measurement capabilities of the microwave scanning equipment.

Calibration Procedures

Microwave and x-ray absorption techniques are used during three-phase relative permeability experiments to monitor oil, brine, and gas saturations in core samples. While microwave attenuation is predominantly affected by brine saturation, x-ray absorption is affected by the saturation of all three phases, although attenuation by the 10% iodododecane tag in the oil phase is significantly greater than attenuation due to the brine or gas phases. A method was developed to account for this absorption of x-rays by the brine and gas phases, so that a more accurate oil saturation could be inferred.

Figure 3 shows the microwave calibration for brine saturation at one position within a core. Figure 4 shows x-ray calibration curves for oil/gas and oil/brine systems for a single scan position within a core. Similar correlations are developed for other positions located at 7-mm intervals along the length of core. A single x-ray calibration curve is sufficient for determining the saturation of the tagged phase when only two phases are present. For three-phase-flow systems, a measured x-ray intensity may represent many saturation conditions, as shown in figure 4, e.g. for $\ln(I) = 11.11$. However, microwave scans are taken during three-phase flow tests to calculate the brine saturation at each scan position within a core. The x-ray calibration curves (log of x-ray intensity versus oil saturation) set an upper and a lower bound on oil saturation for a given x-ray intensity reading. Since the brine saturation is known from the microwave adsorption, the true oil saturation can be approximated by linear proportionality between these oil/brine and gas/brine calibration curves.

Extension of Results and Conclusions From the Previous Report

A study was performed during fiscal year 1987 to study the effects of viscosity on three-phase relative permeability, and the results were reported.¹ Since then, more work has been done. Thus, the previous results were evaluated further to obtain additional information. It was found that the Berea cores from the same quarried block can have significantly different relative permeability values and the saturation envelopes in ternary diagrams can also show dissimilar behavior. The brine and oil relative permeabilities were found to be independent of the oil-phase viscosity. However, the relative permeability to gas was considerably lower for the higher viscosity

oil, suggesting the possibilities of coupled flow in the gas channels. More detail is provided in the following sections.

Newly Acquired Data

The data from experiments performed recently have not been fully analyzed. A comprehensive treatment will be performed, and the results will be reported. Nevertheless, the raw data are shown in figures 5 and 6, and tables 1, 2, and 3.

EFFECT OF OIL (NONWETTING PHASE) VISCOSITY ON THREE-PHASE RELATIVE PERMEABILITY

The following discussion on the observations and conclusions is added to supplement previously reported results. This addition has been possible because new information is continuously being obtained in this project. More detailed information has been reported.¹

RESULTS AND DISCUSSION

The properties of the four Berea sandstone cores used in this study are listed in table 4. All four cores were obtained from the same quarried block, and their absolute gas permeabilities ranged from 590 to 690 md. Cores 1 and 4 showed quite different behavior in three-phase relative permeability compared to cores 2 and 3. The major differences were in residual saturations when all three phases were present. Thus, the saturation envelopes on ternary diagrams for three-phase flow were not identical in size and location. However, cores 2 and 3 showed similar behavior. The exact reason for this dissimilarity is not known. Since the cores were cut from the same block and had approximately the same absolute permeability and porosity, they were less likely to differ in lithology, pore structure, or pore size distribution. The cores were never cleaned during these experiments; thus, there was little possibility that wettability changes would occur.

When the results were analyzed, considerable data scatter was observed, similar to the observations by some previous investigators. This scatter was perhaps caused by operational difficulties inherent in three-phase flow experiments. Manual interpolation was found to be difficult and impractical because of the extent of data scatter. A three-dimensional interpolation was

required for each ternary diagram. The data were plotted by graphical contouring with the help of a three-dimensional interpolation technique described previously.¹ Some of the contour plots required additional smoothing. Because of the computer interpolation and smoothing involved for some of the curves, the values should be considered approximate. However, the trends are definite, and qualitative comparison is quite justified.

The effect of oil-phase viscosity on three-phase relative permeability is shown in figure 7 in which the ternary diagrams for the 4-cP oil system (core 2) and the 47-cP oil system (core 3) are compared. As mentioned previously, cores 2 and 3 showed similar characteristics. A total of 28 three-phase flow runs were performed on core 2, and 60 similar runs were performed on core 3. The graphical contouring technique could only be used successfully to draw isoperms of values for which enough experimental data were available. When the number of data points for a specific value was small, the resulting curves were found to be ambiguous.

As shown in the ternary diagrams, the brine isoperms are linear and have approximately the same value for both the 4- and 47-cP systems. This implies that the wetting-phase relative permeability depends only on its own saturation. It also implies that the wetting-phase relative permeability is independent of oil-phase viscosity.

The oil isoperms for both 4- and 47-cP oil systems are concave towards the 100% oil apex, indicating that the relative permeability to oil is a function of all three saturations. The 10% isperm in the 4-cP system appears to occur at a slightly lower saturation, but the other data points (not shown as isoperms because of being few in number) for higher values (such as 20%) indicate that the relative permeability to oil for a 4-cP oil is the same as 47-cP oil. Thus, oil viscosity does not seem to affect the relative permeability to either oil or brine.

The gas isoperms are also concave towards the 100% gas apex, indicating the gas relative permeability depends on all three saturations. However, unlike brine and oil relative permeabilities, the gas isoperms are seen to occur at approximately 15 to 20% higher gas saturations for a 47-cP oil than for a 4-cP oil. More studies are needed before a definite conclusion about the effect of oil-phase viscosity on three-phase relative permeability can be made; therefore, further research is being performed. From many theories that

explain this behavior, one that seems plausible is that a different flow mechanism is involved when a higher viscosity oil is present, possibly a plug-type (or coupled) flow. Equally likely is the possibility that the pore-level physics of the flow mechanism described in the literature may be inadequate to describe three-phase flow.

The above analysis was performed on data from two rather similar cores. A second analysis was performed to determine how the results are effected when the data of dissimilar cores are combined. The resulting ternary diagrams are shown in figure 8. In these diagrams, the number and the size of the curves are much larger than those in figure 1 because more data are available when the results of several cores are combined. However, the resulting curves have large curvatures because of the difference in three-phase saturation envelopes of dissimilar cores. This observation, therefore, implies that the three-phase relative permeability curves, when developed by use of more than one core (even if from the same quarry), may not be reliable unless they have been shown to be similar in other tests, such as capillary pressure, pore-size distribution, or two-phase relative permeabilities.

EXTENSION OF OBSERVATIONS AND CONCLUSIONS

The following additional observations and conclusions were made as a result of the re-evaluation of the steady-state experimental study performed on four Berea sandstones:

1. Two of four samples obtained from the same quarried block showed dissimilar characteristics. For example, the saturation envelopes in the ternary diagrams for three-phase flow were not identical. The relative permeabilities for these dissimilar cores were also significantly different.
2. In three-phase flow, the relative permeability to brine is a function of only the brine saturation because the shape of the brine isoperm in a ternary diagram is linear. However, both oil and gas relative permeabilities are functions of all three saturations. The shape of the oil and gas isoperms in their respective ternary diagrams is concave towards their 100% saturation apex.

3. The brine and oil relative permeabilities were found to be independent of the oil-phase viscosity. However, the relative permeability to gas was considerably lower for the higher viscosity oil. This comparison was made between two separate sets of experiments in which the oil-phase viscosities were 4- and 47 cP, and two different but similar cores were used.

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TABLE 1. - Relative permeability results from core No. 11

$$k_L = 560 \text{ md}$$

$$\mu_w = 1.02 \text{ cP}, \mu_o = 1.20 \text{ cP}, \mu_g = 1.76 \times 10^{-2} \text{ cP}$$

Two-phase water¹/oil

s_w	s_o	k_{rw}	k_{ro}
0.065	0.349	5.18×10^{-2}	5.66×10^{-3}
0.674	0.326	5.65×10^{-2}	6.18×10^{-4}
0.660	0.340	4.57×10^{-2}	1.99×10^{-2}
0.654	0.346	4.83×10^{-2}	2.10×10^{-2}
0.629	0.371	4.82×10^{-2}	1.61×10^{-1}
0.573	0.427	1.73×10^{-2}	1.83×10^{-1}
0.530	0.470	6.73×10^{-3}	2.56×10^{-1}
0.500	0.500	8.31×10^{-3}	3.16×10^{-1}
0.610	0.390	2.98×10^{-2}	8.53×10^{-2}
0.605	0.395	2.90×10^{-2}	8.29×10^{-2}
0.632	0.368	4.41×10^{-2}	3.92×10^{-2}
0.639	0.361	3.09×10^{-2}	2.74×10^{-2}
0.665	0.335	5.09×10^{-2}	9.75×10^{-3}

¹1% by weight NaCl brine.

TABLE 2. - Relative permeability results from core No. 12

$$k_L = 515 \text{ md}$$

$$\mu_W = 1.02 \text{ cP}, \mu_O = 4.30 \text{ cP}, \mu_g = 1.76 \times 10^{-2} \text{ cP}$$

Two-phase water¹/oil

s_W	s_O	k_{rw}	k_{ro}
0.590	0.410	4.0×10^{-2}	8.6×10^{-2}
0.566	0.434	3.8×10^{-2}	1.8×10^{-1}
0.536	0.464	2.2×10^{-2}	2.0×10^{-1}

Three-phase water¹/oil/gas

s_W	s_O	s_g	k_{rw}	k_{ro}	k_{rg}
0.550	0.249	0.201	1.11×10^{-2}	4.08×10^{-3}	4.26×10^{-4}
0.565	0.232	0.203	1.30×10^{-2}	2.39×10^{-3}	5.17×10^{-4}
0.562	0.243	0.195	2.39×10^{-2}	2.06×10^{-3}	1.00×10^{-3}
0.554	0.239	0.207	1.15×10^{-2}	2.11×10^{-3}	1.37×10^{-4}
0.553	0.226	0.226	1.28×10^{-2}	2.25×10^{-3}	6.33×10^{-4}
0.535	0.252	0.213	9.94×10^{-3}	4.14×10^{-3}	8.08×10^{-5}
0.586	0.214	0.200	1.25×10^{-2}	1.71×10^{-3}	2.12×10^{-4}
0.558	0.237	0.206	8.32×10^{-3}	2.35×10^{-3}	1.94×10^{-4}
0.533	0.254	0.212	6.27×10^{-3}	2.94×10^{-3}	9.38×10^{-5}
0.517	0.253	0.230	5.95×10^{-3}	2.82×10^{-3}	6.88×10^{-5}
0.539	0.260	0.200	9.25×10^{-3}	3.94×10^{-3}	1.06×10^{-4}
0.541	0.272	0.188	5.80×10^{-3}	6.56×10^{-3}	1.42×10^{-5}
0.517	0.281	0.203	5.57×10^{-3}	6.30×10^{-3}	1.34×10^{-5}
0.523	0.318	0.159	5.32×10^{-3}	5.85×10^{-3}	2.08×10^{-5}
0.511	0.269	0.220	4.77×10^{-3}	7.28×10^{-3}	3.58×10^{-5}

¹1% by weight NaCl brine.

TABLE 3. - Relative permeability results from core No. 13

$$k_L = 586 \text{ md}$$

$$\mu_W = 1.02 \text{ cP} \quad \mu_O = 47.8 \text{ cP}$$

Two-phase water¹/oil

s_W	s_O	k_{rw}	k_{ro}
0.564	0.436	9.18×10^{-3}	1.44×10^{-1}
0.531	0.469	4.03×10^{-3}	1.89×10^{-1}
0.471	0.529	2.65×10^{-3}	3.72×10^{-1}

¹1% by weight NaCl brine.

TABLE 4. - Basic core properties

Core No.	Permeability, md	Porosity, %	Dimensions, cm
1	550 (brine)	21.4	L=15.25; W=2.7; H=3.92
2	687 (N ₂)	22.5	L= 7.7; W=2.69; H=3.87
3	680 (N ₂)	25.18	L= 7.5; W=2.69; H=3.87
4	690 (N ₂)	22.65	L= 7.7; W=2.67; H=3.88

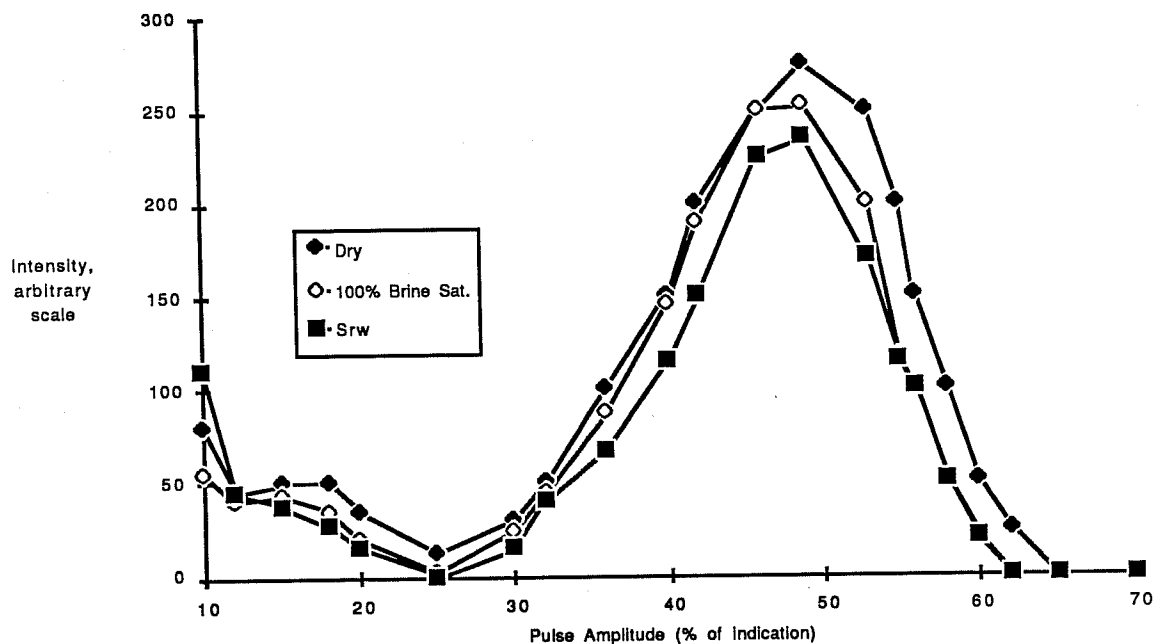


FIGURE 1. - Pulse height distribution curves for core No. 13.

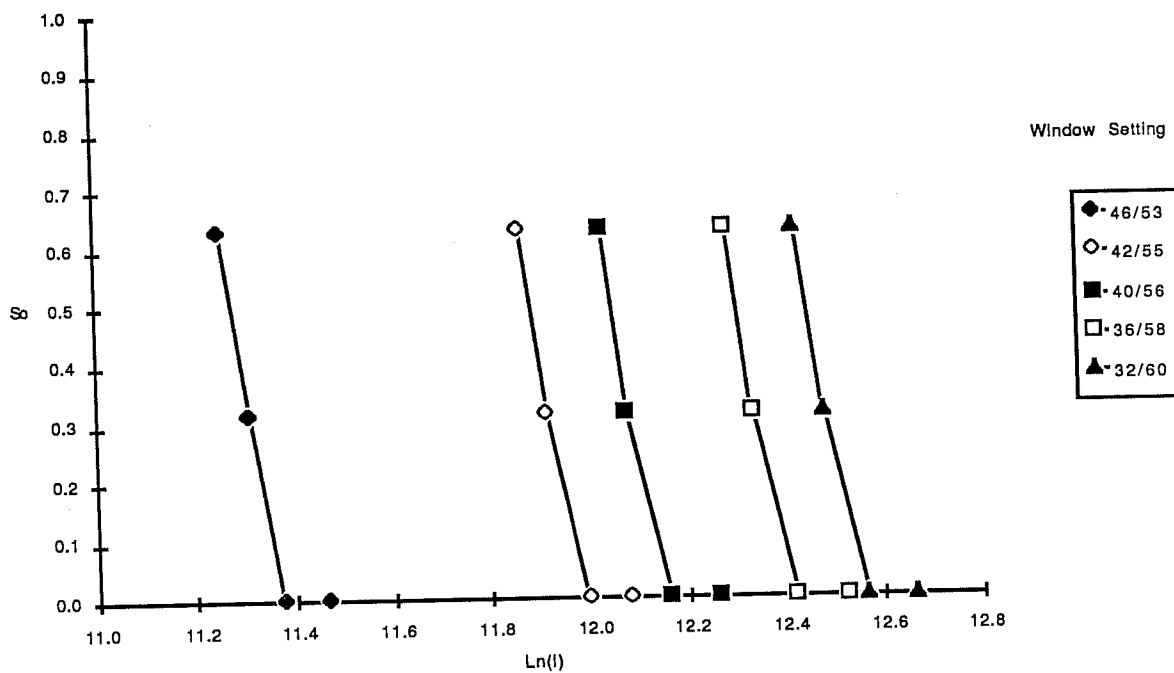


FIGURE 2. - Core No. 13 x-ray calibration for one position with various window settings.

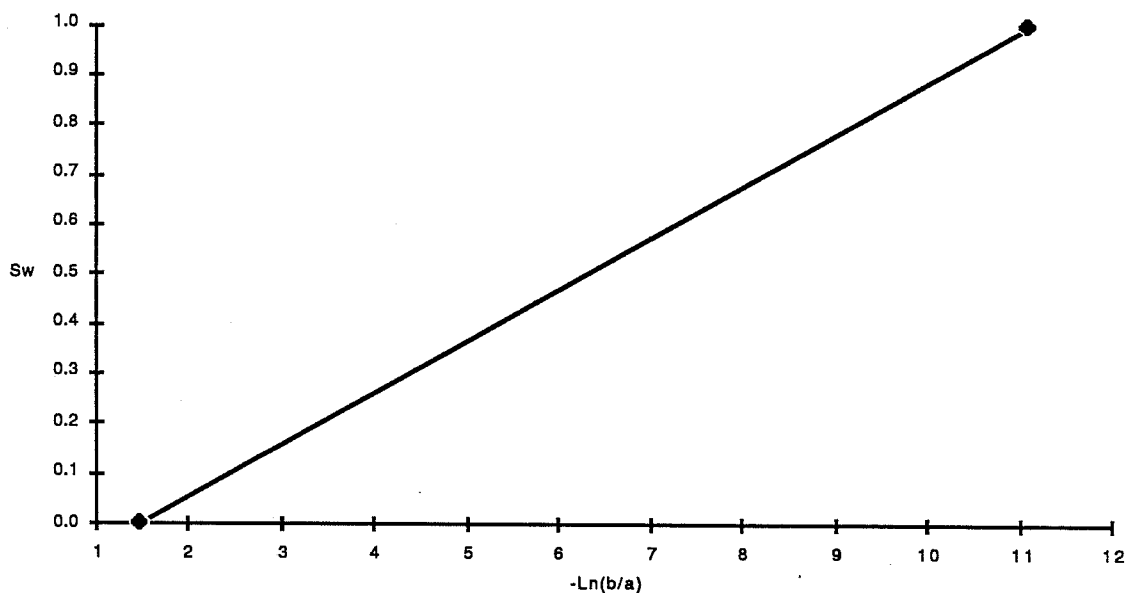


FIGURE 3. - Microwave calibration for brine saturation for one position within core No. 12.

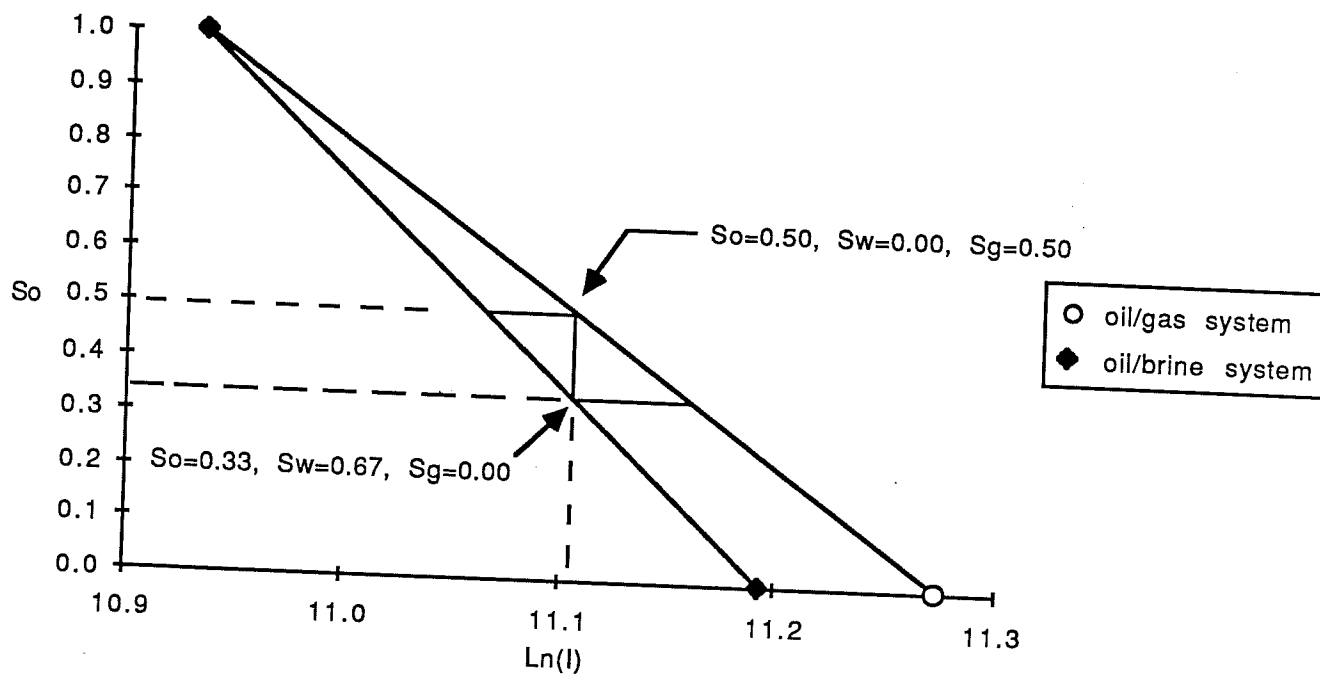


FIGURE 4. - X-ray calibration curves for oil/gas and oil/brine systems.

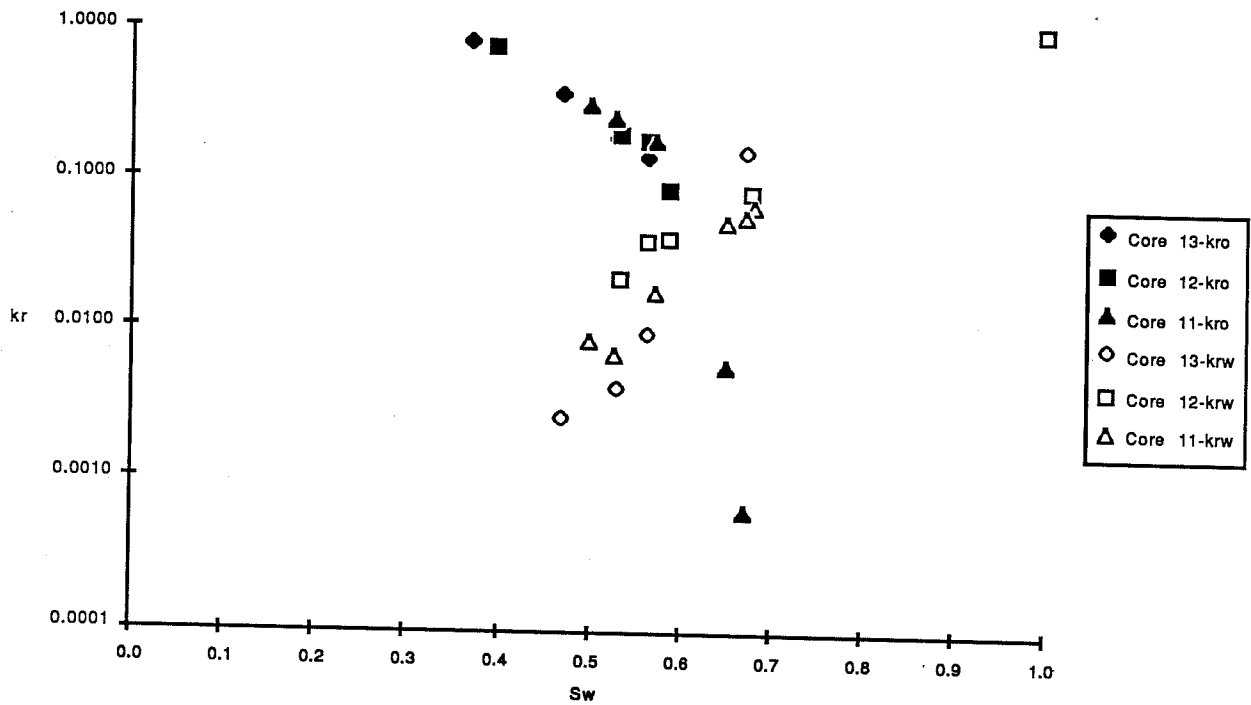


FIGURE 5. - Two-phase relative permeability data: semi-log plot, oil viscosities for cores 13, 12, and 11 are 47.8, 4.3, and 1.2 cP respectively.

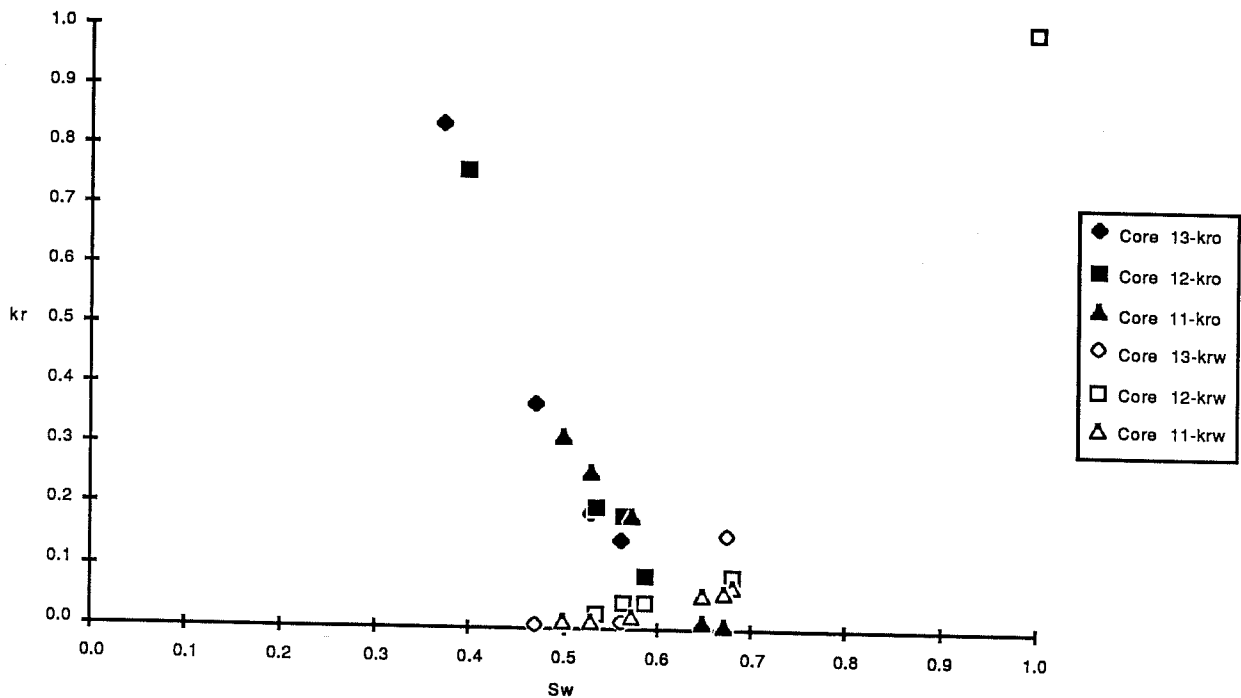


FIGURE 6. - Two-phase relative permeability data: linear scales.

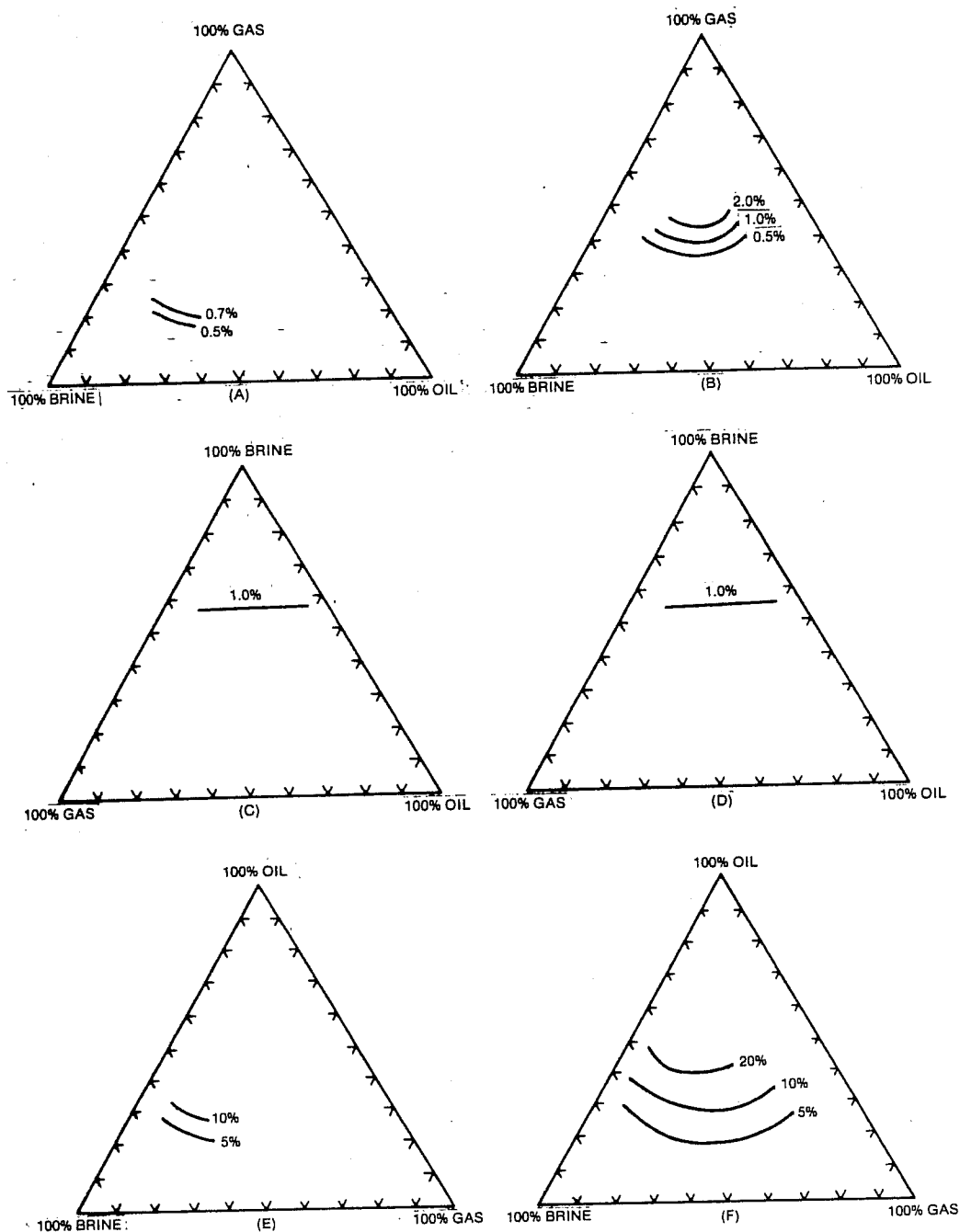


FIGURE 7. - The comparison of three-phase relative permeability curves on ternary diagrams between a low and a high oil-phase viscosity system: (A) gas isoperms, 4-cP oil (B) gas isoperms, 47-cP oil (C) brine isoperm, 4-cP oil (D) brine isoperm, 47-cP oil (E) oil isoperm, 4-cP oil (F) oil isoperm, 47-cP oil. The low and high viscosity data were generated on two similar Berea cores. Only those runs are included in which all three phases were mobile.

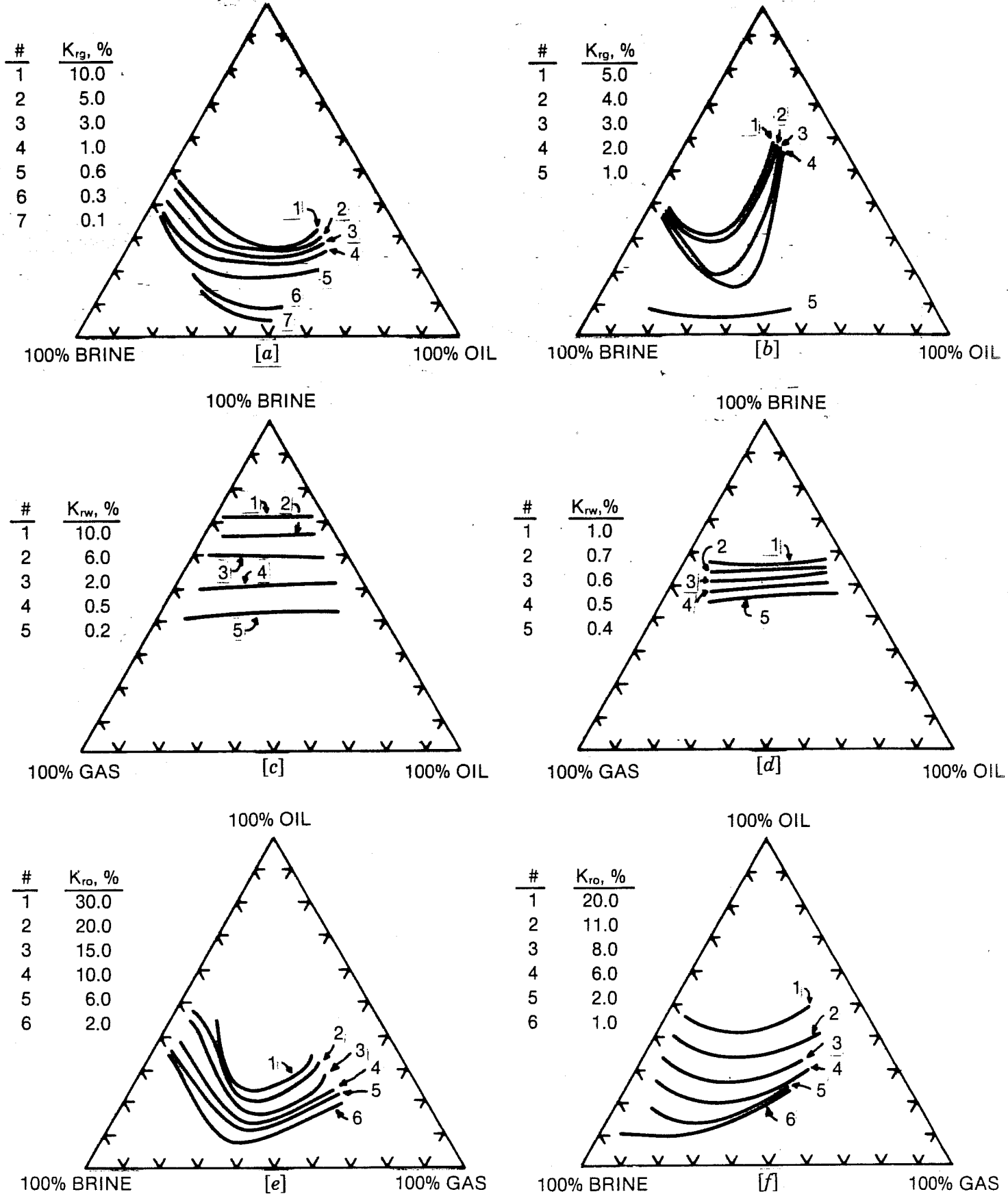


FIGURE 8. - The effect of combining the three-phase relative permeability data generated on dissimilar cores for a low and a high oil viscosity system: (a) Gas isoperms, 4-cP oil (b) gas isoperms, 47-cP oil (c) brine isoperms, 4-cP oil (d) brine isoperms, 47-cP oil (e) oil isoperm, 4-cP oil (f) oil isoperms, 47-cP oil. All the data are considered, including those which had one or two phases stationary.

APPENDIX A
SUMMARY OF LITERATURE REVIEW ON THREE-PHASE
RELATIVE PERMEABILITY EXPERIMENTS

Steady-state/unconsolidated sand:

Lewrett and Lewis (1941)	5 samples/64 readings	kerosene + SAE 50
Reid (1956)	1 sample/98 readings	diesel
Snell (1962)	1 sample/250 readings	diesel + SAE 30

Steady-state/sandstones:

Saraf and Fatt (1967)	10 samples/10 readings	kerosene/Deuterium
Schneider & Owens (1970)	6 samples/few runs	hydrocarbon close out
Caudle et al. (1951)	1 sample/few runs	reservoir oil

Steady-state/Berea sandstone:

Spronson (1982)	4 samples/few runs	30 cP oil/water + glycol
O'Meara and Lease (1983)	1 sample/8 readings	white mineral oil
Corey et al (1956)	9 samples/1 test	polar oil

Unsteady-state/Berea sandstone:

Donaldson & Dean (1966)	2 samples/120 readings	paraffinic hydrocarbons
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Unsteady-state/reservoir rock:

Sarem (1966)	2 samples/8 tests	Soltrol-130
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DETAILS

Leverett and Lewis (1941)

Method:	Single core dynamic (steady state)
Core:	Uncon. sands of different origins, 5-16D, 41-44%.
Fluids:	1.4% NaCl, kerosene + 55% SAE 50 (polar), nitrogen
Mobility ratio:	1.86 to 20.22; isoperms for all phases were found to be independent of the visc. of oil phase.
Packing:	dry-screened sand in a sand cell, vertically upward flow, hand shaking, 80-200 mesh USS,
*OBP, BP: ¹	none
Operational:	permit gas, oil and brine simultaneously until equilibrium
Cleaning:	flush with CO ₂ , then with water
Samples and measurement:	5 samples, 64 runs
Typical K _{ro} :	0.01 @ 21%, 0.25 @ 50%, 0.60 @ 72%
End effect:	fairly high Δp
Hysteresis:	random history, thus cannot be determined
Measurement:	conductivity of brine between electrodes, gas by expansion of gas after closing-in cell (at low pressure brine was injected to boost pressure) near cell-ends through perforated rings.
Calc. proc:	Darcy's law; manual smoothing
Errors:	$\pm 6\%$ in dead vol., $\pm 2\%$ for equilibrium; $\pm 1-2\%$ in k_o due to lack of equilibrium, large errors due to dead space and lack of equilibrium possible.
Remarks:	refers to Botset (Trans. AIME 1940, 136, 91) claiming uncon. sands differ from cons. rocks.
Functional:	$k_{rw} \rightarrow f(s_w)$; k_{rg} , $k_{ro} \rightarrow f(s_w, s_o, s_g)$
Spread:	"Considerable spread of data was encountered in the relative permeabilities to gas and water" --- "Errors due to inaccuracies in measurements were negligible compared to the lack of reproducibility that is characteristic of this type of work."

¹ OBP, BP \rightarrow Overburden pressure, backpressure.

Visual:

"Visual examination under the microscope shows the presence of an oil film (in some cases containing a very small amount of finely divided water) through which oil flows around each gas bubble. It is not clear whether all gas bubbles are connected. However, the gas bubbles are observed to move jerkily, as opposed to the generally smooth flow of water (and oil when gas bubbles are absent or stationary). This jerky motion of the gas imparts similar motion to at least part of the oil, which therefore would be expected to move easier than in the absence of gas at the same oil saturation. Likewise, presence of the oil should act as a partial hindrance to gas flow, both of these conclusions are borne out by the curves of figures 5 and 6."

Snell's Comment:

"Leverett and Lewis's results can be interpreted to give oil isoperms convex towards the 100% oil saturation apex (on the usual triangular diagram) over the zone of investigation. It is believed these workers may have given unwarranted emphasis to the two-phase oil/gas and water/oil results from some earlier experiments. The oil/gas isoperms exist only in the line of zero water saturation and cannot be approached in a naturally water-wet system."

Snell's Comment:

"Of the 75 oil-phase results given by Leverett and Lewis, it seems that 30 give a poor correlation with their deduced isoperms."

Sarem's Comment: "The oil isoperms reported by Leverett of Lewis also have a tendency to parallel the oil iso-saturation lines at the central saturation region where all three phases flow simultaneously."
 "At high oil saturations and low water saturations, the isoperms reported by Leverett and Lewis have a definite curvature."

Caudle, Slobod and Brownscombe (1951)

Method: Penn State (steady)
 Core: cons. reservoir rock, 25 md; 23%
 Fluids: air, original oil at connate brine sat., polar and live oil.
 OBP, BP: No OBP; seems to have some unknown BP
 Operational: oil sat. was decreased by simultaneous increase of gas and brine
 Cleaning: none
 Samples and Measurements: One sample;
 Typical k_{ro} : 0.025 @ 30%; 0.2 @ 50%; 0.56 @ 72% based on k/k_{rw} @ SWC
 End Effect: neglected, thought to be small; flow rates were low to avoid rate effect in gas presence, 2 to 5 days equilibrium time.
 Hysterisis: Oil ↑, Brine ↑, Gas ↑; noticed hysterisis but ignored the effect
 Wettability: plugs were not 100% water-wet
 Measurement: vac. distillation after removing the core at each point.
 Calc. proc: Darcy's law
 Remarks: Incomplete study, preliminary results. Fig. 8 (p. 148) is good example of sat. gradients
 Functional: $k_{rw}, k_{ro}, k_{rg} \rightarrow f(s_w, s_g, s_o)$; all three relative perms. are function of all three sat.

Snell (1962) [similar procedure and results by Hosain (1961)]

This study was a continuation of Reid (1956) by removing errors.

Method:	Penn State (steady state)
Core:	Uncons. sand, 7.1D, 35%, highly homogeneous and clean
Fluids:	air, diesel + SAE30, 0.584% NaCl (polar oil) 5 cm/min max for brine and 102 cm/min for gas, much below turbulence.
Mobility Ratio:	8 and 4
Packing:	80-100 mesh BSS silver sand, mechanical shaking, under vacuum in water, 4' OD perspex tube, 4' long, 9 sections, 10 pressure taps.
OBP, BP:	1-4 mm H ₂ O BP
Cleaning:	None
Samples and Measurements:	One sample (repacked once), 250 tests.
Typical k_{ro} :	0.075 @ 50%, 0.25 @ 70%
End Effect:	Eliminated by making measurements in a zone away from the ends of the core which showed uniform saturation, the end effect was noticable up to 12 cm from the inlet face and up to 20 cm from the outlet.
*Hysterisis:	DD, DI, II, ID, evaluated results independently from each other on the basis of sat. history.
Wettability:	water-wet, but results suggest a partial change to oil-wet

*DD,DI,II,ID → First letter in the pair indicates the direction of sat. change for water, whereas second letter indicates for oil: D implies drainage, I implies imbibition.

Measurement: gas from Neutron bombardment on a single spot in the middle of the chosen section of the cell. Water from RCl circuit at radio frequency (thus measuring electrodes conductivity), pressure in water-phase through alundum barriers. Points along cell. Uniform zones of S_w selected

Errors: $\pm \frac{1}{2}\%$ at low s_w to 2% at high s_w ; $\pm 2\%$ for s_g shown in calib, $\pm \frac{1}{2}\%$ error in k_o

Remarks: $k_{ro}, k_{rg}, k_{rw} \rightarrow f(s_o, s_g, s_w)$
 "Hosain, using the same apparatus as Snell, but using a non-polar oil-phase, has shown that for these oils the behavior is independent of the direction in which saturation change are made. However, where polar oils were used, a distinct differences between drainage and imbibition was noticed."
 "However, it would not be surprising if the degree of wettability were the controlling factor. Clarification of this aspect will be made if an investigation of three-liquid-phase relative permeabilities can be studied; such studies may become important in miscible/immiscible secondary recovery processes."
 "In the present reinterpretation only nine runs showed large discrepancies."
 "The DD condition was separate (lower) from ID, II and DI cases, the reason for this difference is not readily apparent but may be due to a partial change from water-wet to oil-wet because of the polar oils used in the earlier work."
 "This analysis established that even in homogeneous sandpack, even after prolonged flow at constant rate, considerable saturation variations could occur over the length of the flow cell." Only 10% to 20% in the middle was homogeneous.

Donaldson of Dean's

Comment:

"Snell's water and oil isoperms were similar to those obtained by Reid, but his gas isoperms were convex toward 100% gas sat."

"Snell demonstrated the dependence of the oil phase on the saturation history."

Reid (1956) (PhD Thesis)

Method: Single core dynamic (steady-state)

Core: Uncons. sand 50-100 D, 38%

Fluids: air, diesel, 0.58% NaCl (polar oil)

Mobility Ratio: 8

Packing: 25-36 mesh BSS, wet sand, hand tamping

Samples and Measurements: 98 measurement

End Effect: Eliminated by making saturation and pressure measurements away from the ends of the core

Hysteresis: ignored

Measurement: Water by conductivity between two electrodes.
Differential absorption of gamma-ray (depends on s_w and s_o). Pressure in water phase through fine sand barriers, equal points along cell.

Errors: $\pm 1-2\%$ water, $\pm 5\%$ in gas, errors in k_o not given; electrode corrosion experienced differential absorption of x-rays possibly caused errors.

Remarks: $k_{ro}, k_{rg}, k_{rw} = f(s_o, s_g, s_w)$

Sarem's Comment: "The curvature of Reid's isoperm is opposite to that reported by Leverett and Lewis" and also previous investigations in general.

Donaldsen & Dean's

Comment: "Reid obtained gas isoperms which were concave towards 100% gas saturation indicating higher permeability to gas in the presence of two liquids."

Corey, Rathjens, Henderson and Wyllie (1956)

Method: capillary pressure method (Hasslers, steady-state)

Core: cons. Berea sandstone, nine samples were used for 1 test

Fluids: CaCl_2 brine, polar oil

Operational: oil was replaced by gas, whereas brine was kept stationary by using semi-permeable membrane. Test cores were saturated with brine prior to oil, brine saturation was constant, one core for one point saturation level.

Cleaning: each core was used only twice

Samples and Measurements: nine samples, 1 test

Typical k_{rO} : 0.01 @ 19%, 0.2 @ 50%, 0.45 @ 75%

End Effect: minimized due to semi-permeable membranes

Hysterisis: oil drainage, oil is replaced by gas; brine is kept constant by using silicine treated semi-permeable membrane. Hysterisis is avoided by using different core samples for each saturation level.

Wettability: water-wet

Measurement: gravimetric

Calc proc: a new method of estimating k_r 's is proposed based on ratio of areas in capillary curve. Assumes that brine completely fills smaller pore and wets the larger ones.

Remarks: "gas relative permeability curves obtained on cores with brine present were identical with those obtained on the same core with no brine present."
"An increase in oil permeability for a given oil saturation occurs when the water saturation is increased at the expense of gas saturation. This effect is most pronounced in the region of low water saturations." "Thus in a water-wet system, as oil is displaced by water, the oil moves into larger pores at the expense of the gas, as the latter is displaced from the system."

Functional:

$k_{rw} = f(s_o)$; k_{rw} in water-wet = k_{ro} in oil-wet, $k_{rg} = f(s_g)$; $k_{ro} = f(s_w, s_o, s_i)$; k_{ro} and k_{rg} with brine = k_{ro} and k_{rg} without brine when plotted against total liquid saturation. However, very small range of saturation does not justify generalizations such as $k_g = f(s_g)$.

"Two of the cores had gas relative permeability curves which differed from those of all other cores, particularly in the high liquid saturation regions. Therefore, data from these cores were not used in constructing the gas isoperms."

"The scatter in the data through which the gas isoperms are drawn undoubtedly reflects the result of using several different cores to represent one medium."

"It has been repeatedly observed that the gas (non-wetting phase) flow behavior is much more sensitive to changes in pore geometry than is the response of wetting phase."

Sarem's Comment:

"This is also supported by Corcy who indicates that, at the region of saturation where all three phases flow, the relative permeability to oil may be assumed to be a function of only oil saturation, at the expense of swell error."

Saraf and Fatt (1967)

Method:

single core dynamic (steady-state)

Core:

Boise sandstone, 1.6D, 26%, 6"L, 1½" Dia.

Fluids:

N₂, kerosene, deuterium oxide

Mobility Ratio:

1.87

Packing:

core in Teflon sleeve

Operational:

brine sat. is kept constant by keeping Δp and q_w constant, the oil sat was lowered in steps by flowing increasing amounts of gas until the oil stopped flowing

Sample and Measurement: 10 samples, 10 tests
 Typical k_{ro} : .01 @ 32%, .17 @ 50%
 End Effect: eliminated by measuring sat. and pressure 1" away from the ends
 Hysterisis: Eliminated by using different core samples; no saturation was established twice in the same core; brine constant, oil drainage
 Wettability: water-wet
 Measurement: NMR for kerosene sat.; brine by assuming constant and determining by extraction at the end of the test.
 Calc Proc: darcy's law
 Errors: large scatter in data due to the use of different core plugs; k_{rw} and k_{rg} drawn from two-phase data. Δp measured in upper zone only. However, oil sat. was reproducible within 1%, in water within 2%.
 Remarks: $k_{rw}, k_{rg} = f(s_w)$ or $f(S_g)$; $k_{ro} = f(s_o, s_g, s_w)$
 'Sat. distribution observed along x-axis even after 1 month."
 " $k_r - S$ is not a unique function of sat. but depends on the sat history even in steady state tests."
 "To avoid hysterisis effect, no saturation was established twice in the same core. Different cores were used in each run even though a slightly greater scatter in the data had to be accepted because no two cores were identical."
 "At the max. gas sat attained (40%) the k_{rg} was less than 5%."
 "Because of this low relative gas permeability, experimental error was high."

Donaldson and Dean (1966)

Method: unsteady-state displacement
Core: Berea sandstone, 200 md, 19%, 10.5 cm, 2" = dia; and Arbuckle limestone, 425 md, 11%, 7.8 cm, 2" dia
Fluids: Soltrol, 0.584% NaCl, air (In the text it says paraffinic hydrocarbon oil, distilled water and air)
Mobility Ratio: 1.1334 cp @ 75° F
Packing: core mounted in plastic
OBP, BP: none
Operational: oil and brine displaced by gas injection only, sat. ranged from 100% water to 100% oil, flow was vertically down at 45° angle
Cleaning: slowly flowing through the cores a stream of trichloroethane, followed by IPA and water, then dried with air
Samples and Measurements: 2 samples, 120 readings
Typical k_{ro} : 0.5 @ 50%, 2.5 @ 70%
End Effect: minimized by using high rates, as high as 0.5 pv/min
Hysterisis: ignored
Wettability: not sure due to cleaning
Measurement: volumetric measurements of terminal flow rates, terminal saturation calculated by Welges
Calc. Proc: ext. of Welges two-phase technique to three-phase.
Errors: expect to be large, large collecting vessels, tilted core
Remarks: k_r 's = f (s_o , s_w , s_g)

Sarem (1966)

Method: unsteady-state
Core: reservoir core, Brea-Olinda field, 257 md, 24%, 7 cm long, 3.2 cm dia, s_{wi} = 61.1%, and Berea outcrop, 275 md, 20%
Fluids: 1.3 cp oil (Soltrol-130), 1.16% NaCl, air
Mobility Ratio: 1.3

Operational: saturate with one liquid then displace with other immisible liquid at least until b.t, then both liquids are displaced by gas in a standard displacement apparatus

Cleaning: cleaned, dried, then saturate with one fluid

Samples and Measurements: 2 samples, 70 readings, 8 tests

Typical k_{ro} : .002 @ 38%; .026 @ 49%

End Effect: neglected

Hysterisis: ignored, perhaps all DDI

Measurement: volumetric measurements of terminal rates, terminal sat. calculated by Welge's

Calc Proc: extension of Welge's unsteady-state method to three-phase

Remarks: "Assume that the fractional flow of each phase may be taken to be a function of the saturation of only that phase in the limited region of simultaneous flow of all phases (even though in practice this may introduce minor error)"

"The saturation history is taken to be invariant in this study."

"In accordance with our assumption that the relative permeability of each phase is a function of the saturation of that phase only, the isoperms were drawn as straight lines parallel to the iso-saturation lines."

"Note that the initial saturation condition influences both the relative permeability to oil and to water, but only slightly influences the relative permeability to gas" (tested in Berea outcrop only). Lower the initial water saturation, higher the k_{rw} and lower the k_{ro} ; whereas $k_{rg} \neq f(s_{wi})$.

"It has been shown that the k_{rs} for three-phase flow, as in two-phase flow, is influenced by initial saturation conditions (similar trend)."

Schneider and Owens (1970)

Method: dynamic (both Penn State and gas drive)
Core: Torpedo sandstone, 370 md, 24%
Fluids: 1.7 cp and 26 cp closeout hydrocarbon fraction
OBP, BP: 200 psig back pressure
Samples and Measurements: 6 sandstones, 2 carbonates
Wettability: both oil-wet and water-wet independent systems,
Measurement: Gas by x-ray absorption, water by electrical
resistivity
Errors: due to low Δp
Remarks: $k_{rw} = f(s_w)$; $k_{ro}, k_{rg} = f(s_o, s_w, s_g)$